RTO West
Filing Utilities Meeting
6/27/00
Portland, OR

Attendees: (For all or a part of the meeting):

Bill Kirby, Portland General Electric	Frank Afranji, Portland General Electric
Bill Pascoe, Montana Power Company	Ted Williams, Montana Power Company
Ray Brush, Montana Power Company	Mark Maher, Bonneville
Peggy Olds, Bonneville	Melanie Jackson, Bonneville
Lauren Nichols, Bonneville	Vickie Van Zandt, Bonneville
Ron Rodewald, Bonneville	Warren McReynolds, Bonneville
Dennis Metcalf, Bonneville	Dave Gilmore, Bonneville
Preston Michie, Bonneville	Chris Reese, Puget Sound Energy
Kimberly Harris, Puget Sound Energy	Carolyn Cowan, Sierra Pacific/Nevada
Randy Cloward, Avista	Richard Goddard, Portland General Electric
Connie Westadt, Sierra Pacific/Nevada	Gary Porter, Sierra Pacific/Nevada
Don Furman, PacifiCorp	Marcus Wood, PacifiCorp
Jim Collingwood, Idaho Power	Lisa Grow, Idaho Power
Chuck Durick, Idaho Power	Bud Krogh, Krogh & Leonard
Kristi Wallis, Neutral Notetaker	John Boucher, KEMA

Agenda

Legal Work Group
Control Areas
RTO Facilities/Potential Impacts of Choices
Framework for Functionality of RTO/What the RTO Will Do
  Identify Major Elements
  Develop Processes
  Decide Size of RTO staff
Pricing Proposal

Agenda Item 1: Legal Work Group

A number of filing utilities raised the concern that issues regarding the Transmission Control Agreement ("TCA") are being closed off prematurely, while noting that they understand that the push to finalize the agreement is being motivated by good intentions. The TCA contains a number of items that are currently being discussed by the work groups and, to some, it does not make sense to try to finalize it until after the work groups have provided their input.

Don Furman stated his understanding of the general rule for work groups – that parties are required to raise issues they are aware of now, but if issues come up later that could not have been anticipated, agreements will be reopened to deal with them. Don will discuss the concern that was raised with Marcus Wood, the leader of the TCA small group. [When Marcus later joined the meeting he commented that the deadlines regarding the TCA had been developed with concurrence in a telephone conference of the legal subgroup dealing with the TCA. He stated that the TCA subgroup members had received e-mails specifying the deadlines and about three weeks had been provided for providing comments. He noted that the ITC had submitted TCA comments at the last legal workgroup meeting and that those comments were included for TCA subgroup consideration. He expressed his concern that while some Filing Utilities and the non-Filing Utilities were actively represented in the Legal Work Group, that a number of Filing Utilities were not actively participating in some of the critical small groups and that the time to get engaged was now. He asked for those Filing Utilities who were concerned to call him.]

Agenda Item 2: Control Areas

John Boucher briefed the group about control area issues, and provided some information regarding the NERC reliability model.

The issues that were discussed included what facilities would be included in the RTO (what is subject to the tariff and operations can be different), and what would the organizational boundary be (RTO-heavy, RTO-light – how to divide up responsibilities).

John Boucher reported on the following work group developments. The Implementation Work Group has been discussing the security authority and are evaluating whether it would be more efficient to contract this role to existing bodies or to have the RTO execute the security function internally.

The Ancillary Services and Congestion Management Work Groups have been meeting jointly and are currently discussing the concept of scheduling coordinators. The implementation work group has agreed that scheduling coordinators should be used. (Scheduling coordinators contract with loads, provides generating resources as necessary, manages its portfolio, submits balanced schedules to RTO, and self provides ancillary services). John Boucher explained that while scheduling coordinators would not replicate control areas, they would perform many of the same functions, and might be an acceptable option to some organizations who currently want to retain their own control areas.

It was noted that there is a tension between the scheduling and balancing functions and that the balancing authority should be independent. Scheduling coordinators would submit final schedules to the RTO and the RTO would be responsible for scheduling interchange. (Questions were raised later about the need for the RTO to be the balancing authority.)

There was considerable discussion about the logistics of scheduling coordinators, including the following points: Scheduling coordinators have been used in the Mountain West ISA and they are required to have software that matches up with ISO's; in other ISOs scheduling coordinators are required to be certified; and FERC would like to see scheduling coordinators become a uniform concept throughout the country.

The following issues were raised: Who would/should be the balancing authority? Does it need to be an entity that is completely independent, or just not have an interest in generation? Would it be acceptable to state regulators for utilities that currently balance generation and load to pay for a third party to provide that service? Some of the filing utilities would like to see the RTO be the sole balancing authority, others would like to keep open the possibility of other parties provide balancing services in addition to the RTO.

Bonneville made a presentation regarding what would be necessary for RTO West control area operations on Day One. The functions of a control area might change as the region moves towards deregulation and a RTO. Right now there are multiple control areas in the potential geographic scope of RTO West. Many of the filing utilities would like to see a single control area as part of the RTO, but recognize that there might need to be a transition to a single control area end-state.

Order 2000 made clear that the RTO has responsibility for short-term reliability. The RTO will also be a one-stop shop, and will be responsible for accepting reservations and making arrangements for transmission, including real-time calculation of TTC and ATC. In order to perform these two functions -- short-term reliability and scheduling, the RTO needs to have visibility of the grid as well as perform some of the other RTO functions such as congestion management. As such, even if at Day One there are still a number of control areas in place, the RTO will need to have an overall control area to ensure visibility for calculation of real-time TTC/ATC and to protect short-term reliability

At the same time, generation owners would like to sell ancillary service products into other control areas as well as their own. Many of these generation owners have a number of responsibilities, including nonpower obligations (fish, other environmental constraints, *etc.*). It is important that the RTO is structured so that generation owners can satisfy all of their responsibilities and be able to sell ancillary services.

When TBL and PBL split, they needed to determine how to change control functionality and divide responsibilities between generation and transmission. They consulted with Ontario Hydro, and agreed on the following principles. BPA suggests that the principles be considered for the RTO:

> As the RTO would not own any generation, the purchase of ancillary services for its overall "control area" responsibilities would be treated equitably (although when unplanned events occur, the location of the resource could be important).

In an emergency and to relieve line overloading, the RTO would need to have direct control of some generation, but this control would not be for purposes of preserving capacity on economy paths (that is the responsibility of the market).

Generation owners would manage their assets and provide reliability services and products in the ancillary services market or through bilateral contracts for service. It might be necessary for the RTO to arrange for some minimum level of generation to run in order to stabilize inventory, but this would be done through market arrangements (although there might be some reliability must run resources).

Generation owners could offer Interconnected Operating Services ("IOS"), a package of services from which the RTO would produce ancillary services for its reliability needs. (IOS is intended to supplement FERC's ancillary service list).

Ontario Hydro developed joint protocols regarding IOS, but also provide that if there is an emergency all bets are off and the RTO will act to protect the reliability of system and can access generation to accomplish this (the RTO pays for the use of such generation).

There was a discussion of the pros and cons of this approach. The following advantages were identified for entities that no longer would operate a control area: eliminates some reporting responsibilities, removes responsibility for system frequency, and management takes the form of scheduling and the responsibility to manage or balance self-provision is eliminated. The following advantages were identified for the RTO and all of its customers by having a single control area: more efficiencies, monetary savings, simplification of NERC reporting, ability to reconcile imbalances earlier, minimization of the amount of regulation necessary for NERC purposes (currently overregulating), savings on operating reserves, and ability to see constraints more easily.

Issues that were raised about this approach included how would to keep track of unmetered generation, whether it is more risky to maintain a single data base, how would interfaces be treated, and how a generation owner would know what load to follow if it did not receive a signal from its control area.

Regarding the last issue, Bonneville responded by stating that one way would be to have load-serving entities estimate their load and set their generation schedules to meet their load curves and, if there are differences in real-time, have the RTO make up the difference.

Bonneville indicated that they have implemented "self-provision" in two ways. The first was to allow entities to self-provide within a metered boundary but, as it was impossible to verify that self-provision was occurring, both Bonneville and the self-provider responded. In order to resolve the uncertainties and minimize over-provision, Bonneville has moved to a system where the control area identifies what is needed for the bigger boundary and a self provider provides its share of that requirement, but doesn't regulate within its boundaries. (The generator would get the signal for its pro rata piece of what the whole boundary needs.) Bonneville recommends that the later approach be used (there is a cheaper bottom line).

A number of issues and concerns were raised, including the following: the recommended approach is very different from what is currently done and parties might have serious concerns about gaming and entities leaning on the system too much; some of the utilities might want to continue to do real-time load following within their metered boundary; the state regulators might be concerned about retaining a balancing authority and the provision of ancillary services within a state.

It was noted that all of these issues had been discussed by the work group, and that substantial progress was being made towards reaching agreement.

The group agreed that they wanted to go to a single control area and, if possible, it would be good to have it in place on Day One. If that is not possible, there should be a transition plan and that plan should be as straightforward and simple as possible. Other than that, it was decided that as the work groups were fully engaged on the relevant issues and were making good progress, it didn't make sense to provide more guidance at this point, with the following exceptions: consider the balancing issue, clearly define relevant terms (to avoid confusion), and estimate the cost of having a single control area on Day One (both with respect to reliability and dollars).

Agenda Item 3: RTO Facilities/Potential Impacts of Choices

There was initial discussion of the three data sets being prepared by the Pricing Work Group. The Implementation Work Group is comfortable with the FERC 7-factor test. The Planning Work Group, ideally, would like the RTO to have planning responsibility for those facilities that could affect the transfer capability of the main grid, but they recognize that if more facilities are included in the tariff, there might need to be some planning responsibility for the additional facilities (under the theory that the parties that pay for facilities should have a voice in the decision making).

There was not a lot of discussion on this issue, and consensus was not reached. That said, many of the Filing Utilities support the use of the 7-factor test. Ultimately FERC (with input from the states) will make the decision of what is included and parties that are not comfortable with the use of the 7-factor test (or have concerns about the transmission owners' application of the test) would be able to raise their concerns with FERC.
It was noted that there are special issues for Bonneville regarding the 7-factor test (FERC may weigh in on their facilities, but doesn't have jurisdiction). It was also stated that for operational purposes, the focus would be on back-bone facilities, while for pricing and planning purposes there would need to be a link between facilities.

Agenda Item 4: Framework for Functionality of RTO/What the RTO Will Do

Throughout the meeting, there were isolated references to this topic, but it was not the subject of a focused discussion.

Agenda Item 5: Pricing Proposal

PacifiCorp recommends that the Pricing Work Group be instructed to remove area rates for the recovery of the embedded costs of the existing system from the table and focus on company rates. In summary, the proposal provides that the cost of current investments would be recovered from the load of the utilities, including net wheeling agreements, over the life of the assets. Everything new would be recovered on a postage stamp basis. As the existing assets depreciate, the rate component attributable to them will be eliminated. This approach would allow individual transmission owners the latitude to deal with customer issues individually (not one size fits all). It also prevents the problem of immediate cost shifts, as well as dealing with the pricing implications of transmission owners joining the RTO subsequent to its formation and transmission owners leaving the RTO. The idea is to keep retail customers largely whole and move gradually to a postage stamp rate.

There are a number of reasons why PacifiCorp is advocating this proposal. While at the time of the IndeGO negotiations the parties understood that FERC would not approve company rates for a significant period of time, since that time FERC has indicated that it would be more receptive. PacifiCorp believes that company rates would eliminate a number of the issues that the parties are currently struggling with, including what facilities to include, cost shifting, and segmentation. By having company rates, the decisions of individual transmission owners will not affect other transmission owners, and transmission owners would have more autonomy in decisions affecting their existing facilities. It would also limit the amount of states that the individual transmission owners have to deal with.

Some of the investor-owned filing utilities have already discussed the proposal, and they would like the thoughts of the Filing Utilities as a whole. If possible, PacifiCorp would like the Filing Utilities to develop a proposal for the RRG.

There are still a number of issues to work through, and those should be identified in the near future. (It was commented that a number of these issues were raised in the IndeGO process concerning company rates and that while PacifiCorp's proposal would simplify some matters, the Filing Utilities should not assume that it would be easy to resolve all of the related issues.) The issues include how to handle: (1) wheeling contracts/transfer payments (trickier now than at the time of the IndeGO discussions as a number of those contracts are now with third parties)(there was disagreement about how long the impacts of those contracts should be reflected in the company rate), (2) how to treat replacements (company rate -- postage stamp rate?), (3) how to treat O & M (initially company rate, then transition to postage stamp?), (4) how to design the pricing structure so that company rates are eventually phased out (in order for the proposal to be acceptable to FERC and some of the parties), (5) how to treat costs of new facilities (postage stamp rate or areas?), (6) what facilities are included in RTO, both initially and in the future (RTO decision, FERC decision, participation of states, need for uniform rule, design a process to decide?), (7) who gets a company rate (some parties concerned that only transmission owners with facilities that pass 7-factor test should be given company rate), (8) how to treat GTAs, and (9) which company rate a new industrial customer would pay.

Montana expressed its concerns that this should be viewed as a transition approach and not the end state. No one disagreed, but when it was suggested that there was no need to define the end state and that there could be a jump ball at some point, some filing utilities expressed concern that they would need more certainty (Idaho).

The was some disagreement about what impact this recommendation, if accepted, would have on the current data collection efforts.

While the Filing Utilities were receptive to the general concept of taking area rates off the table and focusing on company rates, some of the Filing Utilities were not prepared to say that it should be the only alternative to be considered by the Pricing Work Group (Montana, Avista). Further, an issue that will need to be resolved is whether there is a structured transition to a postage stamp rate or whether there is a jump ball, and when that will occur. The Filing Utilities will take this proposal to the RRG tomorrow, and PacifiCorp’s written proposal will be distributed.

Miscellaneous

FERC has volunteered to help out in the discussions, and Bud Krogh asked whether the Filing Utilities would like them to get involved at this point. The parties recognize that FERC should get involved at some point, but there are concerns that if FERC gets directly involved now it would add another layer of process.

Bud Krogh reported that the Adjunct Committee is making good progress and that they are working on a diagram and a short working paper that should be distributed to the Filing Utilities on July 12th. The Filing Utilities could then decide when to present it to the RRG.